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ENERGY FACILITY SITE
EVALUATION COUNCIL

ENERGY FACILITY SITE EVALUATION COUNCIL
P.O. BOX 43172
OLYMPIA, WASHINGTON 98504-3172

IN THE MATTER OF:	**NO. EFSEC/2009-02**
Grays Harbor Energy Center Units 3 and 4	**FINAL APPROVAL**
Grays Harbor Energy, LLC	**NOTICE OF CONSTRUCTION**
Grays Harbor County, Washington	**AND PREVENTION OF**
	SIGNIFICANT DETERIORATION

Pursuant to the Energy Facility Site Evaluation Council (EFSEC) Permit Regulations for Air emissions permits and authorizations (Washington Administrative Code (WAC) 463-60-536(1)) and Chapter 463-78 WAC, the Washington State Department of Ecology (Ecology) regulations for new source review Chapter 173-400 WAC and Chapter 173-460 WAC, the federal Prevention of Significant Deterioration (PSD) regulations Code of Federal Regulations (CFR) Title 40 Subpart 52.21, and based upon the Notice of Construction Application (NOC) submitted by Invenergy, LLC for Grays Harbor Energy, LLC dated October 30, 2009, and the technical analysis performed by Ecology for EFSEC, EFSEC now finds the following:

FINDINGS

1. Grays Harbor Energy, LLC is proposing to add two combustion turbine generators (Units 3 and 4) and a single steam generator to the existing Grays Harbor Energy Center. This will increase the maximum electrical generation capacity by approximately 650 MW, with a total site nominal average capacity of approximately 1,300 MW.

2. Units 3 and 4 would be constructed entirely within the boundaries of the approximately 22-acre Satsop Combustion Turbine (Grays Harbor Energy Center) project site. The site is within the Satsop Development Park in unincorporated Grays Harbor County, near the town of Elma, on the site of the un-built Satsop nuclear facility.

3. The project is proposed to consist of a "power island" in a 2x1 combined cycle configuration consisting of the following major components:

    - Two General Electric (GE) Frame 7FA combustion turbines each with a generator producing up to 175 MW.

    - Two heat recovery steam generators (HRSG) containing supplementary duct burners.

    - One steam turbine with a generator producing up to 300 MW.

    - One auxiliary boiler rated at 29.3 MMBtu/hr.

- One approximately 400 KW emergency generator with an approximately 600 hp diesel engine.

- One firewater pump with an approximately 275 hp diesel engine.

- One forced draft evaporative cooling tower configured in two parallel sets of five cells.

4. The fuel for the combustion turbines, duct burners, and auxiliary boiler will be natural gas only, and will be supplied by an existing pipeline that was constructed as part of the initial site development.

5. The fuel for the emergency generator and firewater pump will be diesel fuel with a maximum of 15 ppm sulfur content.

6. The project will use a water-cooled steam condensation system.

7. The site of the proposed project is within an area that is in attainment with regard to all pollutants regulated by the National Ambient Air Quality Standards (NAAQS) and state air quality standards. The site is approximately 60 kilometers from the nearest Class I area, Olympic National Park.

8. The project application was declared complete on December 24, 2009.

9. The project is subject to the EFSEC Permit Regulations for Air emissions permits and authorizations (Washington Administrative Code (WAC) 463-60-536(1)) and Chapter 463-78 WAC. These regulations adopt and reference applicable state and federal NSR regulations including 173-400 WAC, 173-460 WAC, and 40 CFR 52.21.

10. The project is subject to permitting requirements under the federal requirements of 40 CFR 52.21 as a fossil fuel-fired steam electric generator, one of 28 listed industries that becomes a "major source" when emitting more than 100 tons per year (tpy) of any regulated pollutant. The project has the potential to emit Prevention of Significant Deterioration (PSD) significant quantities of nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), particulate matter (PM), particulate matter less than 10 micrometers (PM_{10}), particulate matter less than 2.5 micrometers ($PM_{2.5}$), and volatile organic compounds (VOC).

11. The project is subject to applicable emission limitations, monitoring, and reporting requirements of New Source Performance Standards (NSPS) 40 CFR 60 Subparts A, Dc, KKKK, IIII, and Appendices A, B, and F.

12. Ammonia (NH_3) and other toxic pollutant emissions from the project are subject to permitting under the requirements of WAC 463-78-005(1) and 005(4), which adopt Chapters 173-400 and 173-460 WAC, respectively. Non-PSD applicable criteria and toxic pollutant

emissions are considered, and permitted if necessary, in the NOC part of this permit. There are no applicable federal NESHAPs for the combustion turbines.

13. The project is subject to the Title 4 Acid Rain provisions, including monitoring and reporting provisions of 40 CFR 72 and 40 CFR 75 Appendix D.

14. The project is subject to 40 CFR Part 70 and is required to file for a modification of the site's then current Title V air operating permit application within 12 months after Units 3 and 4 commence operation.

15. Best available control technology (BACT) as required under 40 CFR 52.21(j) and WAC 173-400-113(2), and toxic best available control technology (T-BACT) as required under WAC 173-460-040(4) (the version adopted by current EFSEC rules) will be used for the control of all air pollutants which will be emitted by the project. The following table lists the project's potential emissions and the turbine and auxiliary boiler BACT control technologies and limits.

Table 1. Project Emissions and BACT Control Technology for Turbines with and without Duct Burning and Auxiliary Boiler

Pollutant	Project Potential to Emit (tpy)*	Combustion Turbines with and without duct burning		Auxiliary Boiler	
		BACT Control Technology	BACT Limit	BACT Control Technology	BACT Limit
Nitrogen Oxides (NO_X)	176.0	Lean premix dry low NO_X turbine burners and low NO_X duct burners with Selective Catalytic Reduction (SCR)	2 ppmvd, with and without duct burning	Ultra-low NO_X burners	9 ppmvd
Carbon Monoxide (CO)	451	Lean premix dry low NO_X turbine burners and low NO_X duct burners with Oxidation Catalyst	2 ppmvd, with and without duct burning	Burner design	50 ppmvd

Pollutant	Project Potential to Emit (tpy)*	Combustion Turbines with and without duct burning		Auxiliary Boiler	
		BACT Control Technology	BACT Limit	BACT Control Technology	BACT Limit
Sulfur Dioxide (SO_2)	63.0	Natural gas fuel	0.0029 lb/MMBtu with duct burning (12-month rolling average), 0.0058 lb/MMBtu with duct burning (1-hour average)	Natural gas fuel	0.0058 lb/MMBtu
Sulfuric Acid Mist (H_2SO_4)	32.1	Natural gas fuel	3.66 lb/hr (12-month rolling average), with or without duct burning	Natural gas fuel	No limit proposed
Volatile Organic Compounds (VOC)	53.1	BACT same as CO	1 ppmvd, with or without duct burning	Burner design	0.004 lb/MMBtu
Particulate Matter (PM) and Particulate Matter less than 10 microns (PM_{10})	170.0	Natural gas fuel with good combustion practices	0.0078 lb/MMBtu with duct bruners and 0.0072 lb/MMBtu without duct burning (filterable plus condensable)	Natural gas fuel	0.005 lbs/MMBtu
Particulate Matter less than 2.5 microns ($PM_{2.5}$) (filterable only)	45.1	Natural gas fuel with good combustion practices	0.0020 lb/MMBtu with or without duct burning (filterable only)	Natural gas fuel	0.005 lbs/MMBtu
Ammonia	162.0	Proper SCR operation	5.0 ppmvd ammonia slip, with or without duct burning	N/A	N/A

* About 107 tons per year of the potential annual CO emissions would be created during normal 8,760 operation of the two turbines. The balance is an estimate of CO that would be created if the maximum start-up and shutdown schedule actually occurs. The other pollutant rates in this column represent normal operation at 8,760 hours annually because that is more than would be emitted under the maximum start-up/shutdown scenario.

16. BACT for the emergency generator and firewater pump engines is that the engine be new and meet the 40 CFR 89 federal engine standards for the year of engine purchase, use of diesel fuel that has a sulfur content of no more than 15 ppm, and nonemergency operation (routine testing and training, etc.) of no more than 100 hours per year for each unit.

17. BACT for the cooling tower is installation of a demister guaranteed to have a drift loss of 0.0005 percent or less of the recirculating water flow rate.

18. Allowable emissions from the new emissions units will not cause or contribute to air pollution in violation of:

    18.1. Any state or national ambient air quality standard.

    18.2. Any applicable PSD increment. Table 2 indicates the maximum Class I and Class II impacts by this project and compares the impact to Significant Impact Levels (SILs). If a SIL is not exceeded, no further increment or cumulative impact analysis is required for the applicable pollutant and area. An AQRV analysis is always required for Class I areas.

Table 2: Class I and Class II Maximum Impact Summary of the Project

Pollutant	Maximum Ambient Class I Area Impact		Class I Area FLM Recommended SIL ($\mu g/m^3$)	Maximum Ambient Class II Area Impact ($\mu g/m^3$)	Class II Area SIL ($\mu g/m^3$)
	Class I Areas With Maximum Impact	$\mu g/m^3$			
NO_2 annual	Olympic NP Mt. Rainier NP	0.0018 0.0006	0.03	0.0889	1
CO 1-hr CO 8-hr	N/A[a]	N/A[a]	N/A[a]	365 18.1	2,000 500
SO_2 1-hr[b] SO_2 3-hr SO_2 24-hr SO_2 Annual	Olympic NP	N/A 0.1596 0.0313 0.0007	N/A 0.48 0.07 0.03	29.9 9.99 1.38 0.0311	30 25 5 1
PM_{10} 24-hr PM_{10} annual	Olympic NP	0.1074 0.0044	0.27 0.08	2.71 0.127	5 1
$PM_{2.5}$ 24-hr $PM_{2.5}$ annual (filterable only)[c]	N/A[d]	N/A[d]	N/A[d]	0.836 0.0485	N/A[d] N/A[d]

a. CO impacts analysis not required in Class I areas.
b. No special Class I area standard exists.
c. $PM_{2.5}$ filterable only is used for impacts analysis and PSD applicability per interim EPA guidance. Total $PM_{2.5}$ is equal to total PM10 when condensable particulate is considered.
d. SILs for $PM_{2.5}$ have been proposed but have not been promulgated.

19. The combined impacts on Class I areas of emissions from the existing site's two turbines and the project's additional two turbines were modeled. As expected, the impact concentrations were about double that of the project alone. For instance, the annual NO_2 impact was 0.0042 $\mu g/m^3$. All impacts were below the FLM recommended SILs.

20. Ambient Impact Analysis indicates the project will have no adverse impact from pollutant deposition on soils and vegetation in any Class I area. The highest impact was on Olympic National Park, with an annual deposition rate of 0.0018 kg/ha/yr for both nitrogen (N) and sulfur (S). Deposition from the project and the two existing turbines modeled at 0.0042 kg/ha/yr nitrogen and 0.0035 kg/ha/yr sulfur. The FLM concern level begins at 0.005 kg/ha/yr for both N and S.

21. For regional haze impact, the Federal Land Managers (FLMs) use a five percent visibility impact as their threshold for possible concern. Olympic National Park was the only Class I area with impacts above that threshold. Using the CALPOST 2 method, six days in the 3-year evaluation period exceed this threshold. Using the newer CALPOST 8 method, two days in the 3-year evaluation period exceeded the threshold. Startup of all 4 turbines (two existing and two new) within a 24 hour period was also modeled. The National Park Service considered both normal operation and startup impacts acceptable. The United States Forest Service determined that it had no concerns with this project based on expected emission increases and the substantial distances to the Forest Service Class I areas.

22. Since the turbine annual NO_X emissions are greater than 100 tpy, an ozone impacts analysis was done. Ozone modeling indicated that impacts were fairly localized, with a maximum increase of 2.25 ppbV in the modeling cell adjacent to the facility. Impacts fell to less than 0.33 ppbV within about 20 km of the facility. Emissions did not impact the traditionally higher ozone sites in Washington. The increase near the Enumclaw (Mud Mountain) observation sites was less than 0.0004 ppbV. This was determined to be acceptable by both Ecology and EPA.

23. The emissions of toxic air pollutants from the project will not exceed any acceptable source impact level (ASIL) established under WAC 173-460-150 or 160.

24. No significant effect on industrial, commercial, or residential growth in the Grays Harbor County area is anticipated due to the project.

25. EFSEC finds that all requirements for new source review (NSR) and PSD are satisfied and that as approved below, the new emissions units comply with all applicable federal new source performance standards. Approval of the NOC/PSD application is granted subject to the following conditions:

APPROVAL CONDITIONS

1. For the Units 3 and 4 combustion gas turbines (CGT) , duct burners , and auxiliary boiler to be constructed and operated:

1.1. Natural gas shall be the only fuel for the CGTs, duct burners, and auxiliary boiler.

1.2. Compliance shall be monitored by written affirmation of the type of fuel burned with each Title V compliance statement.

1.3. Each of the two uprated General Electric (GE) Frame 7FA combustion turbines shall be limited to a maximum design heat input rate of 1895 million British Thermal Units per hour (MMBTU), based on the higher heating value (HHV) of the fuel.

1.4. While the CGT is firing natural gas, the Heat Recovery Steam Generator (HRSG) may combust natural gas in the duct burners up to a maximum heat capacity of 556 MMBTU, HHV. The Permittee shall ensure that the duct burners are not operated unless the associated turbine units are in operation.

1.5. Exhaust gases from the combustion turbine and duct burners shall be directed to a single stack that rises to 54.9 meters above grade with a flue diameter of 5.49 meters.

1.6. The auxiliary boiler shall be limited to a maximum design heat input rate of 29.3 MMBtu/hr.

1.7. With the exception of turbine startups, the auxiliary boiler shall not operate simultaneously with the combustion turbine.

1.8. Exhaust gases from the auxiliary boiler shall be directed to a stack that rises to 14.9 meters above grade with a flue diameter of 0.54 meters.

1.9. Oxides of nitrogen (NO_x) emissions from each CGT and/or duct burner shall be controlled by use of a lean pre-mix dry low-NO_x turbine burners, low NOx burners, a selective catalytic reduction (SCR) control system using ammonia injection, and good combustion practices as BACT. At all times, the exhaust gas from each CGT and duct burner(s) shall be directed to the SCR system.

1.10. Carbon Monoxide (CO) and Volatile Organic (VOC) emissions from each CGT and/or duct burner shall be controlled by lean pre-mix dry low NOx turbine burners, dry low NOx duct burners, oxidation catalyst and good combustion practices as BACT. At all times, the exhaust gas from each CGT and duct burners shall be directed to an oxidation catalyst.

1.11. The natural gas heating value of 23,275 Btu/lb (HHV) shall be used in determining the maximum heat input capacity.

2. For the emergency generator and fire pump:

2.1. Diesel fuel with a sulfur content of 15 ppm maximum shall be the only fuel.

2.2. Compliance shall be monitored by fuel purchase records.

2.3. The emergency diesel generator shall be limited to an electrical capacity of 400 MW and and engine power capacity of 600 horsepower.

2.4. Exhaust gases from the emergency diesel generator shall be directed to a stack that rises to 12.2 meters above grade with a flue diameter of 0.15 meters.

2.5. The Emergency Diesel Fire Pump shall be limited to an engine power capacity of 275 horsepower.

2.6. Exhaust gases from the Emergency Diesel Fire Pump shall be directed to a stack that rises to 10.7 meters above grade with a flue diameter of 0.13 meters.

3. At all times, Permittee shall not discharge or cause the discharge of emissions from each CGT unit, Unit 3 and Unit 4, including when the associated duct burners are or are not firing into the atmosphere in excess of the following:

3.1. Except as provided for during start-up and shutdown, NO_X emission limits:

3.1.1. 2.0 parts per million by volume, dry (ppmdv), 3-hour rolling average, corrected to 15% oxygen (O_2) when the duct burners are or are not firing,

3.1.2. 9.07 kilograms per hour (kg/hr) (20.0 pounds/hour (lb/hr)), 3-hour average, when the duct burners are firing,

3.1.3. 7.22 kilograms per hour (kg/hr) (15.9 pounds/hour (lb/hr), 3 hour average, when the duct burners are not firing,

3.1.4. 1,550 lbs/day, 24-hour rolling average, corrected to 15% O_2, when the duct burners are or are not operating. For purposes of this requirement, emissions during periods of startup, shutdown, and malfunction are used to calculate the 30-day rolling average,

3.1.5. 15 ppmdv @15% O_2 or 0.43 lb/MW-hr, 30-day rolling average, when the duct burners are or are not operating, in accordance with 40 CFR 60 Subpart KKKK. For purposes of this requirement, emissions during periods of startup, shutdown, and malfunction are used to calculate the 30-day rolling average,

3.1.6. Initial compliance with the limits in Condition 3.1 shall be determined in accordance with 40 CFR 60 Subpart KKKK and EPA Reference Method 20, except that the instrument span shall be reduced appropriately for accuracy, and

3.1.7. Continuous compliance with the limits in Condition 3.1 shall be determined by continuous emission monitors for NO_X and O_2. The continuous emission monitoring system (CEMS) must meet the requirements of Approval Condition 15.1.

3.2. Except as provided for during start-up and shutdown, CO emission limits:

3.2.1. 2.0 ppmdv, 3-hour average, corrected to 15% oxygen (O_2), when the duct burners are or are not firing,

3.2.2. 5.53 kg/hr (12.2 lb/hr), 3-hour average, when the duct burners are firing,

3.2.3. 4.39 kg/hr (9.66 lb/hr), 3-hour average, when the duct burners are not firing,

3.2.4. Initial compliance with the limits in Condition 3.2 shall be determined by use of EPA Reference Method 10, except that the instrument span shall be reduced appropriately for accuracy, and

3.2.5. Continuous compliance with the limits in Condition 3.2 shall be determined by continuous emission monitors for CO and O_2. The CEMS must meet the requirements of Approval Condition 15.2.

3.3. Sulfur dioxide emissions limits:

3.3.1. 0.0058 lb/MMBtu, 1-hour average, when the duct burners are firing,

3.3.2. 6.41 kg/hr (14.15 lb/hr), 1-hour average, when the duct burners are firing,

3.3.3. 3.26 kg/hr (7.17 lb/hr), rolling annual-average calculated monthly, when the duct burners are firing,

3.3.4. 0.0029 lb/MMBtu, rolling annual-average calculated monthly, when the duct burners are firing,

3.3.5. Initial compliance with the limits in Condition 3.3 shall be determined using the test methods specified by 40 CFR Part 60 Subpart KKKK including all referenced sections and appendices, or an equivalent method approved by EFSEC and EPA,

3.3.6. Grays Harbor Energy, LLC shall conduct source testing for sulfur dioxide once each operating quarter for the first four operating quarters of each CGT exhaust stack starting with the initial compliance test,

3.3.7. Continuous compliance with the limits in Condition 3.3 3 shall be determined using the methods of 40 CFR Part 60 Subpart KKKK including all referenced sections and appendices. A CEMS or alternative method as allowed by 40 CFR PART 75 shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR Part 75 (acid rain program monitoring),

3.3.8. Continuous compliance with the limits in Condition 3.3 shall be determined through a stack test once every four operating quarters on each CGT stack using the test method prescribed in Condition 3.3.55. The timing of the stack test will coincide with the RATA test for the installed NO_X CEM systems required for that period,

3.3.9. Continuous compliance with all the limits in Condition 3.3 shall be determined through monthly calculation of the SO_2 emissions based on the quantity of natural gas used by each turbine and associated duct burners and the total sulfur content of the natural gas consumed determined according to: Subtracting the quantity of potential SO_2 converted to H_2SO_4 based on the unit specific conversion rate of potential SO_2 to H_2SO_4 determined in Approval Condition 3.4. Total sulfur content of the natural gas shall be determined using the methods specified by 40 CFR Part 60 Subpart KKKK. A CEMS or alternative method as allowed by 40 CFR PART 75 shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR Part 75 (acid rain program monitoring). Not less than once per calendar month Grays Harbor Energy LLC will sample the natural gas burned in CGTs 3 and 4 and associated duct burners., and

3.3.10. Grays Harbor Energy, LLC shall report to EFSEC on a monthly basis the monthly quantity and monthly average sulfur content of the natural gas burned by the CGT and duct burner units at the facility.

3.4. Sulfuric acid mist emissions limits:

3.4.1. 1.66 kg/hr (3.66 lb H_2SO_4/hr), 12-month rolling average calculated monthly, including when the duct burners are or are not firing,

3.4.2. Initial compliance with the sulfuric acid emissions limits shall be determined by EPA Reference Method 8 results, or an equivalent method approved by EFSEC and EPA,

3.4.3. Grays Harbor Energy, LLC shall conduct source testing for the sulfuric acid mist emissions limit once each operating quarter for the first four operating quarters starting with the initial compliance test to determine unit specific conversion factors. The unit specific conversion factors are to be used to apportion the calculated potential SO2 emissions into sulfuric acid mist emissions and SO2 emissions. This testing will be at the same time as the testing required in Condition 3.3.6. ,

3.4.4. After the first four operating quarters of testing, continuous compliance shall be determined through an emissions test on each CGT exhaust stack once every four operating quarters using the methods in Condition 3.4 , and

3.4.5. After four continuous operating years (12 operating quarters) of compliance has been demonstrated, testing may be reduced to once every five calendar years. If any test indicates noncompliance, then the testing schedule reverts to the normal once every four operating quarters until a new 4-year operating period of compliance is demonstrated.

3.4.6. Compliance with the rolling 12-month emission limit shall be determined monthly based on:

3.4.6.1. The quantity of natural gas used by each CGT and duct burners,

3.4.6.2. The total sulfur content of the natural gas consumed according to the procedures outlined in Approval Condition 3.3.9,

3.4.6.3. The conversion rate of potential SO_2 to H_2SO_4 is determined through the Method 8 stack tests required in Approval Conditions 3.4. Until a stack test-based conversion rate is approved by EFSEC, a conversion rate approved by EFSEC may be used, such as the 30% rate estimated in the application.

3.5. Except as provided for during startup and shutdown, Volatile Organic Compound (VOC) emissions limits:

3.5.1. 1.25 kg/hr (2.76 lb/hr), 1-hour average, when the duct burners are not firing,

3.5.2. 1.58 kg/hr (3.48 lb/hr), 1-hour average, when the duct burners are firing,

3.5.3. 1.0 ppmvd, 1-hour average, corrected to 15% O_2, when the duct burners are or are not firing,

3.5.4. Initial compliance with the limits in Condition 3.5 shall be determined by EPA Reference Method 25A or 25B, South Coast Air Quality Management District Method 25.3, or an equivalent EPA method agreed to in advance by EFSEC,

3.5.5. Continuous compliance with the limits in Conditions 3.5.1shall be determined through a stack test once every four operating quarters on each CGT including when the duct burners are or are not firing using the test method prescribed in Condition 3.5.4. The timing of the stack test will coincide with the RATA test for the installed NO_X CEM systems required for that period,

3.5.6. After four continuous operating years (12 operating quarters) of compliance has been demonstrated, testing may be reduced to once every five calendar years. If any test indicates noncompliance, then the testing schedule reverts to the normal once every four operating quarters until a new 4-year operating period of compliance is demonstrated, and

3.5.7. Continuous compliance with all the limits in Condition 3.5 shall be determined through calculation based on hours of operation of each CGT and duct burners, fuel flow, and application of an emission factor derived from stack testing using one of the above referenced methods in Condition 3.5.4.

3.6. Particulate Matter (PM) and Particulate Matter less than or equal to 10 micrometer including condensable PM (PM_{10}) shall be considered equal for this permit, and referenced and reported as PM_{10}. PM_{10} Emissions limitations are:

3.6.1. 207.3 kg/24 hours (456.0 lb/24 hours) of filterable plus condensable PM, when the duct burners are firing,

3.6.2. 147.3 kg/24hours (324.0 lb/24 hours) of filterable plus condensable PM, when the duct burners are not firing,

3.6.3. 0.0078 lbs/MMBtu , filterable plus condensable PM, 1-hour average, at 15% O_2, when the duct burners are firing,

3.6.4. 0.0072 lbs/MMBtu, filterable plus condensable PM, 1-hour average, at 15% O_2, when the duct burners are not firing,

3.6.5. Initial compliance with the limits in Condition 3.6 shall be determined by use of EPA Reference Methods 5, 201, or 201A, plus Reference Method 202, or an equivalent EPA PM_{10} test method approved by EFSEC. Use of EPA Reference Method 5 assumes all filterable particulate is PM_{10}. Use of EPA Reference Method 201 or 201A assumes that the mass of filterable PM is equal to the mass of filterable PM_{10}. If Method 201 or 201A is used, the mass of particulate retained in the cyclone shall be determined and reported,

3.6.6. The results of the filterable and condensable particulate analyses shall be reported as total particulate, filterable particulate, and condensable particulate,

3.6.7. Continuous compliance with the limits in Condition 3.6 shall be determined by an annual emissions test using the methods indicated above,

3.6.8. After the initial four years of tests have been completed, compliance with the limits in Condition 3.6 shall be tested once every five years unless the initial four years of testing indicates noncompliance with the limitations, then the testing frequency remains annual until four consecutive years of testing indicating compliance is achieved. If a once every 5-year test indicates noncompliance, the testing frequency reverts to yearly until four consecutive years of testing indicating compliance is achieved,

3.6.9. The timing of these annual emissions tests shall coincide with the annual RATA testing, and

3.6.10. Initial and continuous compliance with the limit in Condition 3.6 shall be determined by calculating the emissions rates based on the amount of natural gas consumed and using emission factors determined from source test data.

3.7. Particulate Matter less than or equal to 2.5 micrometer ($PM_{2.5}$) :

3.7.1. 51.8 kg/24 hours (114 lb/24 hours), filterable only, when the duct burners are firing,

3.7.2. 0.0020 lbs/MMBtu , filterable, 1-hour average, at 15% O_2, when the duct burners are or are not firing,

3.7.3. 36.8 kg/24 hours (81 lb/24 hours), filterable only, when the duct burners are not firing,

3.7.4. Initial compliance with the limits in Condition 3.7 shall be determined by use of EPA Reference Methods 5, 201, or 201A, or an equivalent EPA $PM_{2.5}$ test method approved by EFSEC. Use of EPA Reference Method 5 assumes all filterable particulate is $PM_{2.5}$. Use of EPA Reference Method 201 or 201A, assumes that the mass of filterable PM is equal to the mass of filterable $PM_{2.5}$. If Method 201 or 201A is used, the mass of particulate retained in the cyclone shall be determined and reported,

3.7.5. Continuous compliance shall be determined by an annual emissions test on each CGT exhaust stack using the methods indicated above,

3.7.6. After the initial four years of tests have been completed, compliance with the limits Condition 3.7 shall be tested once every five years unless the initial four years of testing indicates noncompliance with the limitations, then the testing frequency remains annual until four consecutive years of testing indicating compliance is achieved. If a once every 5-year test indicates noncompliance, the testing frequency reverts to yearly until four consecutive years of testing indicating compliance is achieved,

3.7.7. The timing of these annual emissions tests shall coincide with the annual RATA testing, and

3.7.8. Initial and continuous compliance with the limits in Condition 3.7 shall be determined by calculating emissions rates based on the amount of natural gas consumed and using emission factors determined from source test data.

4. At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from the auxiliary boiler in to the atmosphere, in excess of the following:

4.1. Shall not exceed 2,500 hours of operation per year.

4.2. NO_X emissions limitations:

4.2.1. 0.146 kg/hr (0.32 lb/hr), 1-hour average,

4.2.2. 9 ppm at 3% O_2, 1-hour average,

4.2.3. Initial compliance shall be determined within 180 days of installation in accordance with 40 CFR 60, Appendix A, Reference Method 7E, or an equivalent EPA method agreed to in advance by EFSEC. The span and linearity calibration gas concentrations shall be appropriate to the NO_X concentration limits specified in this condition,

4.2.4. Continuous compliance will be determined through periodic stack tests performed at least once every 60 calendar months after the initial compliance test, and

4.2.5. Emissions shall be determined by monthly calculation using fuel consumption and emission factors based on testing conducted in Approval Condition 4.2.3 and 4.2.4.

4.3. CO emissions limitations:

4.3.1. 50.0 ppm, 1-hour average, corrected to 3.0% O_2,

4.3.2. 0.49 kg/hr (1.08 lb/hr) , 1-hour average,

4.3.3. Initial compliance shall be determined by EPA Reference Method 10 or an equivalent EPA method agreed to in advance by EFSEC. The span and linearity calibration gas concentrations in Method 10 shall be appropriate to the CO concentration limits specified in this condition,

4.3.4. Continuous compliance shall be determined through periodic stack tests performed at least once every 60 calendar months after the initial compliance test, and

4.3.5. Continuous compliance shall be determined by monthly calculation using fuel consumption and emission factors based on testing conducted in 4.3.

4.4. SO_2 emissions limitations :

4.4.1. 0.0058 lb/MMBtu/hr, 1-hr average, corrected to 3% O2,

4.4.2. 0.0029 lb/MMBtu , annual average, calculated monthly,

4.4.3. Initial compliance shall be determined by EPA Reference Method 8, or an equivalent EPA method approved in advance by EFSEC, 4.4.4. Continuous compliance shall be determined by monthly calculation using fuel consumption and total sulfur content of the natural gas consumed in the boilers, and

4.4.5. Natural gas sulfur content shall be measured and reported through methods defined in Approval Condition 3.3.

4.5. VOC emission limitations:

4.5.1. 0.004 lb/MMBtu, 1-hour average, corrected to 3% O_2,

4.5.2. 0.055 kg/hour (0.12 lb/hr), 1-hour average, corrected to 3% O_2,

4.5.3. Initial compliance shall be determined by EPA Reference Method 25A or 25B, or an equivalent EPA method agreed to in advance by EFSEC,

4.5.4. Continuous compliance shall be determined by monthly calculation using fuel consumption and an emission factor derived from stack testing conducted in Approval Condition 4.5.3. and 4.5.5., and

4.5.5. Continuous compliance shall be determined through periodic stack tests using one of the above referenced EPA methods, taken at 5 year intervals after the initial compliance test.

4.6. PM/PM_{10}/$PM_{2.5}$ emissions limitations:

4.6.1. 0.005 lbs/MMBTU, 1-hour average, filterable plus condensable PM10 at 3.0% O_2,

4.6.2. 0.067 kg/hr (0.147 lb/hr), filterable plus condensable PM10 at 3.0% O_2,

4.6.3. Initial compliance with the limits in Condition 6.5 shall be determined by either EPA Reference Methods 5, 201, or 201A, or an equivalent EPA method agreed to in advance by EFSEC. Use of EPA Reference Method 201 or 201A assumes that the mass of filterable PM is equal to the mass of filterable PM10,

4.6.4. The results of the filterable and condensable particulate analyses shall be reported as total particulate, filterable particulate and condensable particulate,

4.6.5. Continuous compliance shall be determined by monthly calculation using fuel consumption and an application of an emission factor derived from stack testing conducted under this Condition 4.6, and

4.6.6. Periodic stack test, using the above specified methods, taken at 5-year intervals after the initial compliance stack test.

5. At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from the emergency generator into the atmosphere, in excess of the following:

   5.1. Be operated only as needed for its maintenance, for training, and for emergency power,

   5.2. Not exceed 100 hours operation in any consecutive 12-month rolling average period for maintenance, testing, and training,

   5.3. Meet applicable federal new engine standards (40 CFR 60 Subpart IIII, which references 40 CFR 89) for engines sold in 2010 or for the year of purchase, whichever is later,

   5.4. Compliance with Conditions 5.1 and 5.2 shall be monitored by installing and operating a nonresetable hour meter with monthly recording of the operating hour meter reading to determine the operating hours, or by automated data collection. The reason for operation shall be logged,

   5.5. Compliance with Condition 5.3 shall be by initial certification of the engine manufacturer,

   5.6. NO_X and SO_2 emissions shall be calculated and reported using operating data such as hours of operation, emission factors, and fuel data. Reporting shall be per Condition 16, and

   5.7. The emergency generator shall not be operated for testing and/or maintenance during startup of any of the CGTs,

6. At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from the fire pump into the atmosphere, in excess of the following:

   6.1. Be operated only as needed for its maintenance, for training, and for emergency fire suppression,

   6.2. Not exceed 100 hours operation in any consecutive 12-month period for its maintenance, for training, and for emergency fire suppression,

   6.3. Meet applicable federal new engine standards (40 CFR 60 Subpart IIII) for engines sold in 2010 or in the year of purchase, whichever is later,

   6.4. Compliance with Conditions 6.1 and 6.2 shall be by installing and operating a nonresetable hour meter with monthly recording of the operating hour meter reading to determine the operating hours, or by automated data collection. The reason for operation shall be logged,

   6.5. Compliance with Condition 6.3 shall be by initial certification of the engine manufacturer,

   6.6. NO_X and SO_2 emissions shall be calculated and reported using operating data such as hours of operation, emission factors, and fuel data. Reporting shall be per Condition 16, and

6.7. The emergency water fire pump shall not be operated during startup of any of the CGTs.

7. At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from the Cooling tower into the atmosphere, in excess of the following:

7.1. 8.60 kg PM_{10}/day (19.0 lb/day), 24-hour average,. This emission limit is achieved when the following two work practice standards in Approval Conditions 7.2 and 7.3 are accomplished,

7.2. The drift eliminators have been installed in accordance with manufacturer's specifications to achieve a drift loss of 0.0005 percent of the recirculating water flow rate,

7.3. The cooling water 7-day average TDS content is less than 1,800 ppmw,

7.4. Initial compliance shall be determined by no later than 180 days after the corresponding CGTs and duct burners commences commercial operation GHE shall obtain an affirmative report certified by the cooling tower drift eliminator manufacturer, based on an on-site inspection of the completed installation, that its product has been installed in accordance with its specifications, and has a drift loss of 0.0005% or less of the recirculating water flow rate,

7.5. Continuous compliance with Approval Condition 7.2 shall be determined by maintaining the assembled cooling tower drift eliminators consistent with manufacturer's recommendations as described in the operating manual for the cooling tower,

7.6. Initial compliance with Approval Condition 7.3 shall be demonstrated no later than 180 days after the corresponding CGTs and duct burners commences commercial operation pursuant to the following conditions: Measure the water's TDS content in accordance with the following procedures: Collect a grab sample of the cooling water at least once per day for seven consecutive operating days, analyze each sample in accordance with Standard Methods, 18th Ed., Method 2540 C or EPA Method 160.1, at 40 CFR Section 136.3, and

7.7. Prior to operation of the cooling tower, Grays Harbor Energy, LLC shall submit to EFSEC, a report describing the manufacturer's recommendations for installing, operating, maintaining, and testing the drift eliminators.

8. Annual total emissions on a 12-month rolling average basis from the units specified in this permit and notice of construction shall not exceed the emission limits for each of the pollutants specified in the following table:

Pollutant	Total Facility[a] (tons/year)[a]
NO_X	176
CO	451
SO_2	63
H_2SO_4	32.2
PM/PM_{10}	170[b]
$PM_{2.5}$	45.1[c]
VOC	53.1
NH_3	162

a. Includes the emissions from start-up and shutdown events .
b. PM and PM_{10} includes condensable PM.
c. $PM_{2.5}$ is filterable only. Actually, all PM is about $PM_{0.1}$, so difference is due to condensables.

8.1 Annual emission limits are derived from the estimated overall emission contribution from emission and operating limits, including periods of startup and shutdown. By the last day of each month the permittee shall, using monitoring data collected pursuant to the requirements of this permit, calculate and record the monthly emissions of each pollutant in the table for the preceding month. By the last day of each month, the permittee shall calculate and record the rolling 12-month emissions of each pollutant in the table by using the monthly emissions calculated for the previous 12 months.

9. Start-up and shutdown for Units 3 and 4:

9.1. Each CGT is limited to 130 cold startups per calendar year and two warm and hot start-up events per calendar day. This limitation does not apply during the period between initial firing of a combustion turbine for testing purposes and 180 days following the start-up condition specified in Approval Condition 11.

9.2. A start-up period begins when fuel is first fired in the combustion turbine, and ends when the earlier of approval condition 9.2.1 or 9.2.2 occurs:

9.2.1. The proper operating temperature of the oxidation and SCR catalysts serving an operating CGT has been achieved as specified in Approval Condition 9.4 and the combustion turbine achieves operational Mode 6, or

9.2.2. One of the following time limits has been reached, as applicable:

9.2.2.1. Five hours have elapsed since fuel was first introduced to the applicable turbine on a cold start-up. A cold start-up is any start-up occurring after the applicable turbine has been shut down for 48 hours or more.

9.2.2.2. Three hours have elapsed since fuel was first introduced to the applicable turbine on a warm start-up. A warm start-up is any start-up occurring after the applicable turbine has been shut down for more than eight but less than 48 hours.

9.2.2.3. Two hours have elapsed since fuel was first introduced to the applicable turbine on a hot start-up. A hot start-up is any start-up occurring after the applicable turbine has been shutdown for 8 hours or less

9.3. The shutdown period begins when the combustion turbine leaves operational Mode 6 and ends when fuel is no longer being introduced to any burner and not to exceed 0.5 hours per shutdown event.

9.4. The proper operating temperature of the oxidation and SCR catalysts and the point at which all dry-low-NOx burners for each combustion turbine are operational shall be determined from the manufacturers design specifications and must be reported in writing to EFSEC before commercial operation of the combustion turbines. Ammonia feed must begin to the SCR as soon as this temperature is achieved during the startup procedure.

9.5. During start-up and shutdown periods, the normal operation limits for NO_X, CO, and VOC in Conditions 3.1.1, 3.1.2, 3.1.3, 3.2.1, 3.2.2, 3.2.3, 3.5.1, 3,5,2, and 3.5.3, respectively, are relieved. Instead, the following limitations apply:

9.5.1. NO_X emissions are limited to 80 Kg/hr, (175 lb/hr) per turbine per startup period based on the total emissions averaged over the time associated with each startup.

9.5.2. CO emissions are limited to 46 Kg/hr, (100 lb/hr) per turbine per startup period based on the total emissions averaged over the time associated with each startup.

9.5.3. VOC emissions are limited to 14 Kg/hr, (30 lb/hr) per turbine per startup period based on the total emissions averaged over the time associated with each startup.

9.5.4. NOx, CO, and VOC emissions are limited to 46 kg (100 lbs), 296 kg (650 lbs), and 19 kg (40 lbs) per turbine per shutdown event, respectively.

9.6. During any start-up and shutdown periods, NO_X and CO CEMs shall record their respective emissions. VOC emissions shall be determined using an emission factor based on stack tests conducted under Approval Condition 3.5..

9.7. Emissions resulting from these start-up and shutdown events shall be included in annual emissions limited in Approval Condition 8, and reported in the quarterly emissions reporting of Approval Condition 16.

9.8. The permittee shall record the time, date, and duration of each startup and shutdown period including when all dry low NOx burners for each combustion turbine are operational and Mode 6 is achieved.

9.9. Operational Mode 6 is defined by the turbine manufacturer as the low emission mode during which all 6 of the burner nozzles are in use, burning a lean pre-mixed gas for steady-state operation.

10. Within 180 days after initial start-up of the auxiliary boiler, the permittee shall conduct the initial performance tests for pollutants as described in Condition 4. For the purpose of this permit, initial start-up occurs when fuel is first introduced to the boiler. The initial performance testing shall be performed by an independent testing firm. A test plan shall be submitted to EFSEC for approval at least 30 days prior to the testing. The initial compliance tests and all subsequent compliance tests shall be conducted at least 90% of rated capacity.

11. Within 180 days after initial start-up of each combustion turbine and/or duct burner, the permittee shall conduct the initial performance tests for pollutants as described in Condition 3. For the purpose of this permit, initial start-up occurs when fuel is first introduced to the subject combustion turbine and/or its associated duct burner. The initial performance testing shall be performed by an independent testing firm. A test plan shall be submitted to EFSEC for approval at least 30 days prior to the testing. The initial compliance tests and all subsequent compliance tests shall be conducted as follows::

11.1. For each series of four (either quarterly or annual) tests, at least two of the tests for each turbine shall be conducted at least 90% of rated capacity and with the duct burners off, and at least two of the test for each turbine shall be conducted at least 90% of rated capacity and with the duct burners at least 90% of rated capacity.

11.2. For each series of once-every-five year tests, at least one of the tests for each turbine shall be conducted at least 90% of rated capacity and with the duct burners off, and at least one of the tests for each turbine shall be conducted at least 90% of rated capacity. The required tests may be conducted in different years.

12. Grays Harbor Energy, LLC shall notify EFSEC in writing at least 30 days prior to:

12.1. Initial start-up of any permitted emissions unit for operational testing and manufacturers certification purposes.

12.2. Initial start-up as defined in Approval Condition 10 and 11.

12.3. The date any emissions testing required by this permit will be performed when the time between tests is specified to be longer than 30 days.

12.4. The date(s) CEMS performance testing or Relative Accuracy Test Audits will be performed.

13. Sampling ports and platforms shall be provided on each CGT stack, after the final pollution control device. The ports shall meet the requirements of 40 CFR, Part 60, Appendix A, Method 20. Sampling ports and platforms shall be available on the auxiliary boiler and emergency generator and fire pump diesel engine stacks. Sampling ports and platforms shall meet the requirements of 40 CFR Part 60, Appendix A, Method 1. Other arrangements may be acceptable if approved by EFSEC.

14. Operating records for emitting equipment:

    14.1. Unless otherwise specified above, operating records shall be information necessary to determine the operational and compliance status of the equipment. The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

    14.2. Specific parameters and acceptable ranges of those parameters shall be specified in the Operation and Maintenance Manual.

        14.2.1. Example operating record information includes, but is not limited to:

            14.2.1.1. Fuel quality.

            14.2.1.2. Fuel consumption during the period (hourly, monthly, etc.).

            14.2.1.3. Unit operating parameters such as:

                14.2.1.3.1. Exhaust temperature.

                14.2.1.3.2. Percent excess air.

                14.2.1.3.3. Output rate (pounds of steam/hour, kW output, etc.).

                14.2.1.3.4. Operating hours during the reporting period and cumulative for the year.

15. Continuous Emission Monitoring Systems (CEMS):

    15.1. CEMS for NO_X and O_2 compliance shall meet the requirements contained in 40 CFR 75, Emissions Monitoring.

    15.2. CEMS for CO shall meet the requirements contained in 40 CFR, Part 60, Appendix B, Performance Specification 4 or 4A, and in 40 CFR, Part 60, Appendix F, Quality Assurance Procedures except that the RATA, linearity check, and leak test schedule shall respect the testing frequency concepts of QA operating quarter and grace period in 40 CFR 75 Appendix B.

16. CEMS and process data shall be submitted quarterly, in written form (or electronic if permitted by the EFSEC) within 30 days of the end of each calendar quarter to EFSEC, its authorized representative (if any).

17. The submittals described in Approval Condition 16 shall be in a format approved by EFSEC that shall include at least the following:

    17.1. Process or control equipment operating parameters,

    17.2. The hourly (or the applicable averaging period) maximum and average concentration, in the units of the standards, for each pollutant monitored,

    17.3. The duration and nature of any monitor down-time,

    17.4. Results of any monitor audits or accuracy checks,

    17.5. Results of any required stack tests, and

    17.6. Results of any other stack tests performed after the initial performance test.

    17.7. The above data shall be retained at the project site for a period of at least five years.

18. For each occurrence of monitored emissions in excess of the emission limits of this permit and notice of construction, the quarterly emissions report (per Approval Conditions 16 and 17) shall include the following:

    18.1. For parameters subject to monitoring and reporting under the Title IV, Acid Rain program, the reporting requirements in that program shall govern excess emissions report content.

    18.2. For all other pollutants:

        18.2.1. The time of the occurrence,

        18.2.2. Magnitude of the emission or process parameters excess,

        18.2.3. The duration of the excess,

        18.2.4. The probable cause,

        18.2.5. Corrective actions taken or planned, and

18.2.6. Any other agency contacted.

19. Grays Harbor Energy, LLC shall have on site, and shall follow, an Operating and Maintenance manual, and an Equipment Start-up, Shutdown, and Malfunction Procedures manual for all equipment that has the potential to affect emissions to the atmosphere. Copies of the manuals shall be available to EFSEC, EPA, or the authorized representative of EFSEC at the facility. Emissions that result from a failure to follow the requirements of the manuals may be considered evidence that emission violations have occurred. The above manuals must be reviewed annually and updated as needed. EFSEC shall be notified whenever the manual is updated.

20. At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate each emission unit, including any associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EFSEC, EPA, or the authorized representative of EFSEC. This information may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

21. The permittee shall construct and operate all equipment, facilities, and systems in accordance with the application and supporting materials submitted by the permittee and in accordance with this permit and notice of construction. Any activity that is undertaken by the company or others in a manner that is not in accordance with the application materials and this permit and notice of construction shall be subject to enforcement under the applicable regulations. Nothing in this permit shall relieve GHE of its obligations under any state, local, or federal laws or regulations.

22. Access to the source, by EFSEC, the authorized representative of EFSEC, or the EPA, shall be permitted upon request for the purposes of compliance assurance inspections. Failure to allow such access is grounds for enforcement action under the federal Clean Air Act or the Washington Clean Air Act.

23. This PSD permit and notice of construction shall become invalid if construction is not commenced, as defined in 40 CFR Part 52.21(b)(9), within eighteen (18) months after receipt of final approval, or if construction of the facility is discontinued for a period of eighteen (18) months, or construction is not completed within a reasonable time. EPA and EFSEC may extend the 18-month period upon a satisfactory showing that an extension is justified, pursuant to 40 CFR 52.21(r)(2).

24. The effective date of this permit shall not be earlier than the date upon which the USEPA notifies EFSEC that the USEPA has satisfied its obligations, if any, under Section 7 of the Endangered Species Act 16 U.S.C. § 1531 et seq., 50 C.F.R. part 402, subpart B (Consultation Procedures) and Section 305(b)(2) of the Magnuson-Stevens Fishery and Conservation Act 16 U.S.C. § 1801 et seq., 50 C.F.R. part 600, subpart K (EFH Coordination, Consultation, and Recommendations).

25. For federal regulatory purposes and in accordance with 40 CFR 124.15 and 124.19: During the public review period for the preliminary determination, any public reviewer may submit a request for a change in any permit condition. If this occurs, the effective date of this permit shall not be earlier than 30 days after service of notice to the commenters and applicant of the final determination accompanied by the associated summary of responses to comments.

    25.1. If a review of the final determination is requested under 40 CFR 124.19 within the 30-day period following the date of the final determination, the effective date of the permit be suspended until such time as the review and any subsequent appeal against the permit are resolved.

    25.2. If there was no public comment requesting a change in the preliminary determination or a proposed permit condition during the public review and comment period, this permit is effective upon the date of finalization subject to consideration of Condition 24 (EPA's ESA requirement) above.

This Prevention of Significant Deterioration permit has been prepared by:

Robert C. Burmark

Robert C. Burmark, P.E.
Science and Engineering Section
Air Quality Program
Washington State Department of Ecology

12/21/2010
Date

ROBERT C. BURMARK
STATE OF WASHINGTON
29848
REGISTERED
PROFESSIONAL ENGINEER
Robert C. Burmark

This Prevention of Significant Deterioration permit has been approved by:

James O. Luce, Chair
Energy Facility Site Evaluation Council
State of Washington

12/21/10
Date

This Prevention of Significant Deterioration permit has been approved by:

Richard Albright, Director
Office of Air, Waste and Toxics
U.S. Environmental Protection Agency, Region 10

12/17/10
Date

25. For federal regulatory purposes and in accordance with 40 CFR 124.15 and 124.19: During the public review period for the preliminary determination, any public reviewer may submit a request for a change in any permit condition. If this occurs, the effective date of this permit shall not be earlier than 30 days after service of notice to the commenters and applicant of the final determination accompanied by the associated summary of responses to comments.

    25.1. If a review of the final determination is requested under 40 CFR 124.19 within the 30-day period following the date of the final determination, the effective date of the permit be suspended until such time as the review and any subsequent appeal against the permit are resolved.

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This Prevention of Significant Deterioration permit has been prepared by:

Robert C. Burmark, P.E. — Date
Science and Engineering Section
Air Quality Program
Washington State Department of Ecology

This Prevention of Significant Deterioration permit has been approved by:

James O. Luce, Chair — Date
Energy Facility Site Evaluation Council
State of Washington

This Prevention of Significant Deterioration permit has been approved by:

12/20/10

Richard Albright, Director — Date
Office of Air, Waste and Toxics
U.S. Environmental Protection Agency, Region 10

NOTICE OF CONSTRUCTION APPROVAL CONDITIONS

1. Ammonia (free NH_3 and combined measured as NH_3) emissions from each CGT exhaust stack:

    1.1. 5.0 ppm, 24-hour average, corrected to 15.0 percent O_2.

    1.2. 8.39 kg/hr (18.5 lb/hr), 24-hour average.

    1.3. The emission limits in Conditions 1.1 and 1.2 are relieved during start-up, shutdown, and scheduled maintenance.

    1.4. Initial compliance for each CGT shall be determined by Bay Area Air Quality Management District Source Test Procedure ST-1B, "Ammonia, Integrated Sampling," EPA Conditional Test Method 027, or an equivalent EPA method approved in advance by EFSEC.

    1.5. Continuous compliance will be determined through use of a CEMS, which meets the requirements of Approval Condition 1.7, or Grays Harbor Energy, LLC may propose alternative means for continuous assessment and reporting of NH_3 emissions for approval by EFSEC. Any proposed alternative NH_3 reporting shall be at a minimum equivalent to a CEMS meeting the requirements of Approval Condition 1.7.

    1.6. The SCR catalyst system treating the exhaust from one CGT shall be repaired, replaced, or have additional catalyst bed installed at the next scheduled outage, following a calendar month when ammonia slip cannot be maintained at or below 4.5 ppm, 1-hour average, corrected to 15.0 percent oxygen, based on the actual operating hours of the CGT. No month with less than 200 hours of actual operation (excluding start-up and shutdown hours) will be used for this evaluation. The outage to repair, replace, or install additional catalyst to the SCR system shall be no later than 12 months after the month the ammonia slip exceeds the 4.5 ppm criteria given above.

    1.7. CEMS for ammonia shall meet the requirements contained in 40 CFR, Part 63, Appendix A, Reference Method 301, Validation Protocol, and 40 CFR, Part 60, Appendix F, Quality Assurance Procedures, or other EFSEC approved performance specifications and quality assurance procedures.

2. Opacity at each CGT exhaust stack:

    2.1. Shall not exceed a 6-minute average opacity of 5%, monitored weekly.

    2.2. Determined by use of EPA Reference Method 9 or an equivalent EPA method approved in advanced by EFSEC.

2.3. Compliance may be monitored weekly by EPA Method 22, or an equivalent EPA method approved in advance by EFSEC. If the observation indicates opacity greater than zero, then:

2.3.1. The owner shall determine the cause of the opacity detected and initiate a program to correct the cause, and

2.3.2. A Method 9 or other EFSEC approved test shall be performed within two non-holiday weekdays.

2.4. If a holiday falls during the 2-day time period, the testing shall be performed on the first non-holiday weekday after the holiday.

2.5. If the turbine is shut down before retesting using Method 9 or other EFSEC approved test, retesting shall be done on the first non-holiday weekday after restarting.

2.6. Installation of a Continuous Opacity Monitoring system on each CGT and duct burner can be substituted for use of EPA Reference Method 9 and Method 22 readings for the CGTs and duct burners. If installed, the continuous opacity monitor must meet the requirements of Approval Condition 2.7.

2.7. Continuous Opacity Monitoring Systems shall meet the requirements contained in 40 CFR Part 60, Appendix B, Performance Specification 1 and in 40 CFR, Part 60, Appendix F, Quality Assurance Procedures.

3. Opacity at the auxiliary boiler exhaust stack:

3.1. Shall not exceed a 6-minute average opacity of 5 percent.

3.2. Determined by use of EPA Reference Method 9 or an equivalent EPA method approved in advanced by EFSEC.

3.3. Compliance may be monitored each operating month by EPA Method 22 or an equivalent EPA method approved in advance by EFSEC. If the observation indicates opacity greater than zero, then:

3.3.1. The owner shall determine the cause of the opacity detected and initiate a program to correct the cause, and

3.3.2. A Method 9 or other EFSEC approved test shall be performed within two weeks.

3.3.3. Installation of a Continuous Opacity Monitoring system on the boiler can be substituted for use of EPA Reference Method 9 and Method 22 readings. If installed, the continuous opacity monitor must meet the requirements of Approval Condition 2.7.

4. Performance monitoring of the auxiliary boiler shall be conducted as described in Appendix A of this permit during each calendar year after the initial performance test was done as described in the PSD portion of this permit.

This Notice of Construction approval has been prepared by:

Robert C. Burmark

Robert C. Burmark, P.E.
Science and Engineering Section
Air Quality Program
Washington State Department of Ecology

12/21/2010
Date

ROBERT C. BURMARK
STATE OF WASHINGTON
29848
REGISTERED
PROFESSIONAL ENGINEER

This Notice of Construction has been approved by:

James O. Luce
Chair
Energy Facility Site Evaluation Council
State of Washington

12/21/10
Date

APPENDIX A

PERFORMANCE MONITORING REQUIREMENTS
AUXILIARY BOILER

1. Introduction:

   a. The purpose of periodically monitoring the exhaust of the auxiliary boiler is to minimize emissions and provide a reasonable assurance that the unit is operating properly.

   b. Periodic monitoring may be conducted with an electrochemical cell combustion analyzer, analyzers used for reference method testing, or other analyzers pre-approved by EFSEC.

2. Monitoring Requirements:

   a. Monitoring to determine emission concentrations of the following constituents shall be conducted for the boiler during each calendar year. The use of an alternative test schedule must be pre-approved by EFSEC in writing.

      Constituents to be Measured
      Carbon Monoxide (CO)
      Nitrogen Oxides (NO_X)
      Oxygen (O_2)

   b. Source operation during monitoring must be representative of maximum intended operating conditions during that year.

   c. Alternative monitoring methodologies must be pre-approved by EFSEC.

3. Minimum Quality Assurance/Quality Control Measures:

a. The analyzer(s) response to span gas of a known concentration shall be determined before and after testing. No more than 12 hours may elapse between span gas response checks. The results of the analyzer response check shall not be valid if the difference between the pre-test and post-test response checks exceeds 10 percent of the pre-test response value.

b. The CO and NO_X span gas concentrations shall be no less than 50 percent and no more than 200 percent of the emission concentration corresponding to the permitted emission limit. A lower concentration span gas may be used if it is more representative of measured concentrations. Ambient air may be used to zero the CO and NO_X cells/analyzer(s) and span the oxygen cell/analyzer.

c. Sampling of the exhaust stack shall consist of at least one test consisting of at least five minutes of data collection following a "ramp-up phase." The ramp-up phase ends when analyzer readings have stabilized (less than five percent per minute change in emission concentration). Emission concentrations shall be recorded at least once every 30 seconds during testing. All test data collected following the ramp-up phase(s) shall be reported to EFSEC or their representative. Alternative testing methods may be utilized provided pre-approval is obtained from EFSEC.

d. If the test results from any monitoring event indicate that emission concentrations may exceed 12 ppmvd NO_X @ 3% O_2 or 50 ppmvd CO @ 3% O_2, the permittee shall either perform 60 minutes of additional monitoring to more accurately quantify CO and NO_X emissions, or initiate corrective action. Additional testing or corrective action shall be initiated as soon as practical, but no later than three days after the potential exceedance is identified. Corrective action includes tuning, maintenance by service personnel, limitation of boiler load, or other action taken to maintain compliance with permitted limits. Monitoring of unit emissions must be conducted within three days following completion of any corrective action to confirm that the corrective action has been effective. Corrective action shall be pursued until observed emission concentrations no longer exceed 12 ppmvd NO_X or 50 ppmvd CO, corrected to 3% O_2. Initiation of corrective action does not shield the permittee from enforcement actions by EFSEC.

4. Reporting:

a. All monitoring results shall be recorded at the facility and reported to EFSEC. The following information shall be included in the report:

(1) Time and date of the emissions evaluation;

(2) Identification of the personnel involved;

(3) A summary of results, reported in units consistent with the applicable emission standard(s) or limit(s);

(4) A summary of equipment operating conditions;

(5) A description of the evaluation methods or procedures used including all field data, quality assurance/quality control procedures and documentation; and

(6) Analyzer response check documentation.

b. Performance monitoring test results shall be corrected to 3% O_2.

(1) Monitoring results shall be reported to EFSEC within 15 calendar days of test completion.